BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates	Docket No. 6690-UR-117

DIRECT TESTIMONY OF GEORGE R. EDGAR AND WAYNE DE FOREST ON BEHALF OF THE CITIZENS UTILITY BOARD

September 1, 2005

I. INTRODUCTION

Q. Please state your names, titles and business addresses.

A. My name is Wayne De Forest. I am the Senior Engineer at Wisconsin Energy Conservation Corporation, 211 South Paterson Third Floor, Madison, Wisconsin 53703.

My name is George R. Edgar. I am the Director of Policy at Wisconsin Energy Conservation Corporation, 211 South Paterson Third Floor, Madison, Wisconsin 53703.

Q. Please summarize your educational background and experience.

A. Mr. De Forest: I have 27 years of experience in the industry performing cost studies, rate design, demand side management design, engineering and research. I worked at the Public Service Commission of Wisconsin for 12 years. My resume is attached as Exhibit ___ (E/D-1).

Mr. Edgar: I have approximately 25 years of experience in the industry, including as a Commissioner on the Public Service Commission of Wisconsin, and over the last 14 years as an energy policy and energy efficiency policy and program design and implementation consultant to various utility, consumer, environmental and public entities including state regulatory commissions. I have recently testified in the WPL CPCN proceeding concerning the Sheboygan Falls Facility; the We-Energies environmental trust bond case and in the most recent past WPL and WPSC rate cases on cost of service and rate design issues. My resume is attached as Exhibit ___ (E/D-1).

Q. On whose behalf are you testifying in this proceeding and what is your assignment?

A. We are testifying on behalf of the Citizens Utility Board (CUB). We were asked by CUB to review the Applicants' electric and natural gas cost of service studies (COSS), the proposed revenue allocations among customer classes, and the proposed electric and natural gas rate designs in this proceeding. In addition, CUB requested we identify potential opportunities for improved rate designs and capturing additional load management opportunities.

Q. Are there valuable improvements that should be made to the way that cost of service studies are currently performed and applied to develop class revenue requirements and to inform rate design?

A. There are several areas where improvements should be made that increase the overall value of cost studies as well as better allow the Commission to address cost of service, class revenue requirement, and rate design issues.

- Cost studies should be done in a way to improve decisions about providing customer equity and improve available rate designs rather than to just produce a broad range of studies with widely varying merits.
- The starting point should be a cost study based on direct allocations with the strongest basis in direct cost causation. This effort provides a good basis from which to consider decisions about costs with less basis in cost causation.
- Cost of service studies and resultant class revenue requirements should identify and recognize meaningful cost differences between various classes rather than lumping all customers into small, medium and large customer classes without consideration of those cost differences. Marginal costs can be useful to provide equity and choices for customers within a rate classification by better identifying usage that is driving future cost increases.

The Commission has historically found it appropriate to use the results of more than one cost study. But, solely using a broad range of cost study results that vary widely on their merits makes it more difficult to make effective decisions on class revenue requirement allocations and rate designs. The Commission has been forced to make decisions on what increase to give to customers primarily by customer size (i.e., small, medium, and large) because more nuanced, appropriate decisions cannot be made based on the very broad range of results from such studies. While the Applicant presents only one cost study, it still proposes nearly the same percent increase by customer size even though its cost study shows large differences in the percent increase to customers within a certain size. Cost studies and class revenue requirements should not ignore that customer consumption characteristics (e.g., when they use energy) cause different cost impacts regardless of whether they are the same size. Marginal cost analysis improves the ability to identify key cost drivers and helps develop improved rate choices that allow customers to better control their bills.

Q. How do you recommend that the Commission use the cost of service information in this record to establish class revenue requirement allocations?

A. We propose that the Commission utilize a "2 step" decision making process for developing class electric rates based on cost of service information rather than just using the aggregate results from various types of cost studies to set percentage increases for the various classes. A "2 step" approach allows the Commission to consider the class impacts on a per kWh basis for each allocation of major groups of costs. Such an approach not only allows the Commission to better assess the reasonableness of overall class revenue requirement allocations (as they are developed), but also the various class impacts, especially from the allocation of those costs with a limited correlation with cost causation.

Q. Please provide a brief description of Step 1 in the proposed decision making process.

A. The <u>first</u> <u>step</u> of the "2 step" approach uses the best factual information available to allocate costs that can be directly allocated based on cost causation. The primary cost categories that should be included in this step involve generation capacity and energy related costs; fuel and purchase power costs; and transmission costs. While some "minimum distribution system" costs are allocated by the Applicant using a "direct" allocator, we explain below that such an approach does not have a sound factual basis in direct or meaningful indirect cost causation.

The TOD cost study typically presented by Commission Staff corrects for the Applicant's errors in allocating fixed and variable production costs (i.e., use of an "equivalent peaker" method and energy allocated on an on- and off-peak basis). Therefore, we use information available at the time of this filing to develop a study similar to the Commission staff TOD study for costs that can be allocated on direct cost causation as the first step in our COSS efforts. The product of Step 1 assigns a cost per kWh to each class for these direct cost allocations to which the product of Step 2 can be added to calculate an overall cost of service.

Q. Please describe Step 2 in the process.

A. The <u>second</u> <u>step</u> considers the appropriate allocation of costs that cannot be allocated based on direct cost causation. The most prominent issues with using the Applicant's method for these types of costs is its choice of allocating most distribution costs to residential customers (i.e., the "minimum distribution system" approach) and the treatment of Administrative & General (A&G) costs. These allocation results are presented on a dollar per kWh impact by rate classification.

The evaluation in Step 2 allows the consideration of whether allocations based on large deviations from the average per kWh are sufficiently justified by some correlation to cost causation to merit the widely disparate rate impacts on the various customer classes. Since there are sound arguments why customers should receive an equal allocation per kWh of any "minimum system" and A&G costs, the evaluation highlights these unjustified extreme impacts per kWh embedded in the Applicant's COSS.

Due to the lack of basis to support such disparate class rate impacts from these cost categories, we moderated the "minimum system" and A&G impacts on a per kWh basis. Our analysis indicates that by placing even high limits per kWh on these allocations with the weakest causation basis, that residential rate increases should be far below those proposed by the Applicant.

The Commission should believe that there is an adequate justification and basis for creating such disparate impacts among customer classes before imposing those disparate rate impacts on specific customers or customer classes. We believe that it is easier for the Commission to make informed judgments about applying per kWh limits to the allocation of costs such as the "minimum system" and A&G costs under the "2 step" approach. This approach provides specific information that allows the Commission to consider the specific rate impacts on various classes of any allocation, but especially for costs that have little direct cost causation. A range of cost studies based on widely disparate approaches and presenting aggregate results does not provide a good or easy basis for the Commission to make similar informed, specific judgments.

Q. What are the results of applying your "2 step" approach to develop the CUB cost of service study and proposed class revenue requirements in this proceeding?

A. The table below combines and summarizes the results from Step 1 and 2. These results are shown below in dollars per kWh for the five categories in step one primarily based on the methods used in the Staff TOD cost study and in step 2 for the five categories of causation where there is a weaker basis for allocations driven by cost causation. (An explanation of these cost categories is set forth below.) It should be noted we have not given an increase to the CP-1 customers due to the per kWh limitations applied to moderate the impact of the Applicant's allocation of "minimum system" and A&G costs. Also, as will be explained in a subsequent Q&A, the assignment of interruptible credits within the cost study (rather than through a rate design credit) may mean the increase listed below is less than justified for those customers.

Causation	RG-1	RG-2	FG-2	CG-1	CG-2	RG-3 OTOU	RG-4 OTOU	FG-4 OTOU	CG-3 OTOU	CG-4 OTOU
Step1 - Cost Based										
Customer	$0.0067	$0.0056	$0.0025	$0.0037	$0.0047	$0.0040	$0.0032	$0.0013	$0.0021	$0.0021
Hookup	$0.0105	$0.0085	$0.0036	$0.0064	$0.0046	$0.0073	$0.0046	$0.0034	$0.0051	$0.0037
Energy	$0.0289	$0.0287	$0.0291	$0.0300	$0.0298	$0.0286	$0.0284	$0.0282	$0.0285	$0.0284
Peak	$0.0205	$0.0177	$0.0185	$0.0184	$0.0174	$0.0167	$0.0151	$0.0143	$0.0161	$0.0154
Capitalize Energy	$0.0022	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021
Step 2 - Other										
Min. Distrib.	$0.0042	$0.0119	$0.0036	$0.0009	$0.0044	$0.0026	$0.0068	$0.0015	$0.0008	$0.0024
Demand Distr.	$0.0024	$0.0022	$0.0027	$0.0022	$0.0040	$0.0021	$0.0022	$0.0021	$0.0017	$0.0022
Linked	$0.0168	$0.0234	$0.0168	$0.0121	$0.0177	$0.0126	$0.0154	$0.0128	$0.0088	$0.0101
General	$0.0100	$0.0128	$0.0135	$0.0070	$0.0096	$0.0076	$0.0088	$0.0113	$0.0055	$0.0062
Other	$0.0029	$0.0032	$0.0195	$0.0021	$0.0024	$0.0024	$0.0024	$0.0192	$0.0018	$0.0019
Total	$0.1009	$0.1064	$0.1109	$0.0920	$0.0991	$0.0876	$0.0892	$0.0971	$0.0840	$0.0819
Present Revenue	$0.0993	$0.1033	$0.0937	$0.0941	$0.0968	$0.0833	$0.0802	$0.0773	$0.0805	$0.0800
Increase	$0.0017	$0.0031	$0.0172	-$0.0021	$0.0022	$0.0043	$0.0090	$0.0198	$0.0036	$0.0019

	GY	MS	RC-S1	CG-S1	FG-6	CG-5	CG-6	CG-20	CP-1
Step1 - Cost Based									
Customer	$0.0026	$0.0077	$0.0055	$0.0036	$0.0006	$0.0007	$0.0009	$0.0005	$0.0002
Hookup	$0.0449	$0.0025	$0.0154	$0.0036	$0.0006	$0.0040	$0.0047	$0.0012	$0.0002
Energy	$0.0256	$0.0255	$0.0251	$0.0257	$0.0287	$0.0298	$0.0294	$0.0295	$0.0285
Peak	$0.0117	$0.0122	$0.0000	$0.0000	$0.0150	$0.0177	$0.0161	$0.0149	$0.0079
Capitalize Energy	$0.0020	$0.0020	$0.0018	$0.0018	$0.0021	$0.0021	$0.0021	$0.0021	$0.0020
Step 2 - Other									
Min. Distrib.	$0.0240	$0.0946	$0.0032	$0.0022	$0.0009	$0.0002	$0.0008	$0.0001	$0.0000
Demand Distr.	$0.0034	$0.0036	$0.0061	$0.0025	$0.0026	$0.0021	$0.0022	$0.0019	$0.0010
Linked	$0.0460	$0.0639	$0.0160	$0.0078	$0.0126	$0.0081	$0.0085	$0.0062	$0.0039
General	$0.0247	$0.0329	$0.0071	$0.0041	$0.0112	$0.0053	$0.0054	$0.0044	$0.0032
Other	$0.0101	$0.0078	$0.0029	$0.0027	$0.0191	$0.0015	$0.0017	$0.0009	$0.0010
Total	$0.1949	$0.2525	$0.0831	$0.0541	$0.0934	$0.0716	$0.0716	$0.0616	$0.0478
Present Revenue	$0.2224	$0.2265	$0.0542	$0.0518	$0.0786	$0.0779	$0.0788	$0.0565	$0.0435
Increase	-$0.0275	$0.0260	$0.0289	$0.0023	$0.0148	-$0.0064	-$0.0072	$0.0051	$0.0043

The cost categories used above in our COSS are described below as well as the cost allocation approach used to allocate costs among the various customer classes.

"Customer" – the customer category includes the cost of being a customer but does not include the capacity to use electricity. Cost of metering and billing customers are included. (Allocated same as Applicant)

"Hookup" – the hookup category includes the cost of the customer being hooked up to the utility side of the distribution system. The cost of the service wires and transformer needed to connect the customer to the utility distribution system are included. (Same as the Applicant)

"Energy" – the energy category includes those costs directly caused by energy usage of the customer. (Allocated on an on- and off-peak basis)

"Peak" are those costs caused by the coincident peak(s) that generation must supply to ensure reliability. (Allocated on 12CP method)

"Capitalized energy" includes the portion of generation and purchased power capacity costs that are incurred to produce lower cost system energy. (Allocated on "energy")

"Minimum distribution" includes those costs the utility allocates based on the number of customers using the "minimum distribution" system method. (Maximum limit on a per kWh basis compared to Applicant COSS per kWh impacts)

"Demand distribution" is the portion of the distribution system Applicant allocates based on distribution system demand as a consequence of the minimum system method. (Allocated same as Applicant but adjusted for "double counting" due to Applicant's application of the "minimum distribution method")

"Linked costs" include those costs that Applicant allocates based on an assumed link to some other costs that have been directly allocated. (Same as Applicant)

"General" includes administrative and general costs. (Maximum limit per kWh for A&G costs compared to Applicant COSS per kWh impacts)

"Other" includes customer service costs which includes energy efficiency program costs along with the cost of wiring farms related to stray voltage. (Same as Applicant)

Q. Have you made adjustments to the way "linked" costs have been allocated to customers?

A. We have been conservative and did not change the assumed relationships in the Applicant's allocation of 'linked" costs. "Linked" costs have only a tenuous link to cost causation by being indirectly allocated based on some perceived relationship to a direct cost allocator. "Linked" costs could be moderated similar to the way we moderated the allocation of "minimum distribution system" costs. Consequently, the increases shown above in our COSS likely overstate the increase per kWh justified for residential customers.

Q. Will you provide a more detailed basis justifying the allocation approaches underlying the CUB COSS?

A. The next section of our testimony provides the specific justifications why the proposed direct allocation methods in the Staff TOD study (and subsumed in our COSS) are appropriate and why the calculation of a "minimum distribution system" is inappropriate as well as, if such an approach is used, fails to justify a per customer allocation of such costs. We also provide information supporting a more equitable allocation of A&G costs.

II. COST OF SERVICE STUDIES

Q. Have you reviewed the Applicant's cost of service studies filed in this proceeding?

A. Yes, we have. Due to expected revenue requirement adjustments by the Commission Staff in this case, Wisconsin Public Service Corporation (WPSC or Applicant) has in fact performed two sets of cost of service studies for its electric and natural gas customers. However, because the methodologies employed in each study are identical, our comments are applicable to both sets of studies.

Q. Do you agree with all of the cost allocation methods used in the Applicant's studies?

A. No. There are important costs that the Applicant has not properly allocated to the various customer classes on the basis of direct cost causation. In addition, the Applicant's treatment of costs that cannot be allocated based on direct cost causation results in a widely disparate impact among customer classes without an adequate justification for such disparities.

Q. What specific cost allocations that can be based on direct cost causation made by the Applicant do you disagree with?

A. Our primary disagreements are with: (1) the allocation of all electric generation capacity costs solely on the basis of demand; (2) the allocation of the capacity/demand costs of the Kewaunee Purchased Power Agreement (PPA) solely on the basis of demand; and (3) the failure to include interruptible loads in the “demand” allocator used to allocate various plant and expense accounts. The appropriate treatment of costs that can be assigned on direct cost causation is a matter that can be determined on the basis of factual information rather than a primary reliance on subjective judgment. Appropriately allocating costs based on direct cost causation, when possible, helps ensure more cost-based and equitable class revenue allocations as well as provides important information to establish cost-based rate designs that present appropriate price signals to customers that can help mitigate future utility costs.

Q. Please discuss the Applicant’s allocation of generation capacity costs.

A. The Applicant has allocated all generation capacity costs based on demand (based on the 12 CP method). This approach to allocating generation capacity costs fails to acknowledge the different purposes for which generation capacity costs are actually incurred, and therefore fails to allocate such costs on the basis of direct cost causation.

If the sole purpose of building a new generation plant is to meet system peak demand, a utility would build a peaking unit (a natural gas combustion turbine). Peaking units have low capital costs, but higher operating costs as they are planned to only be used for limited hours in a year. However, utilities through the use of generation screening curves and other analyses seek to build a new generation unit that will result in the lowest overall system costs to customers not only to meet peak demand but also to reduce overall system energy costs. All customers benefit from these lower overall system energy costs.

Utilities, including WPSC, build intermediate and baseload generation facilities, when appropriate to lower system energy costs. Generation curves developed by WPSC to support approval of its Weston 4 baseload facility indicate which type of generation unit will minimize total system costs depending on the expected time that such units would need to operate to meet expected load.

Q. What is the implication of your foregoing discussion on the appropriate allocation of generation costs in this proceeding?

A. WPSC's generation capacity costs have been incurred to both meet system peak demand **and** to reduce overall system energy costs for the benefit of all customers. To properly assign WPSC's generation capacity costs based on direct cost causation, WPSC's generation costs should be separated into costs incurred to meet system peak demands to ensure reliability and costs incurred to provide lower overall system energy costs.

The capital cost of a peaking unit establishes the appropriate cost factor for WPSC on which to allocate generation capacity costs incurred to ensure reliability. The higher incremental capital costs of intermediate and baseload facilities incurred above the cost of a peaking unit represent the cost for WPSC to attain lower overall system energy costs. This incremental cost difference between the capital cost of a peaking unit and those of a baseload or intermediate unit is sometimes called "capitalized energy" to reflect that higher capital costs are incurred (or "traded off") to achieve the benefit of lower overall system energy costs.

Thus, based on direct cost causation, the allocation on demand-only method used by WPSC fails to reflect the direct cost causation why these generation capacity costs were incurred and will inequitably assign such costs among customer classes, while providing inappropriate price signals for a cost-based rate design (as well as for the design and valuation of demand-side management efforts). Rather, the portion of WPSC's generation costs incurred to maintain system reliability by meeting system peak demand should be allocated based on production demand, while that portion of costs incurred to achieve lower system energy costs (i.e., "capitalized energy" costs) should be allocated on energy. This cost allocation method is termed the "equivalent peaker" method in the NARUC <u>Electric Cost Allocation Manual</u> (1992 at 52-55).

Q. What portion of WPSC's generation costs should be allocated based on demand and what portion on energy?

A. We believe that the 60/40% demand/energy split used by the Commission Staff in several recent cases provides a reasonable, albeit very conservative, basis for identifying the appropriate allocation of WPSC generation capacity costs on a <u>system-wide</u> level (i.e., not for individual plants) between production demand and "capitalized energy." It is important to highlight that such a split is not just an arbitrary percentage or one that is particularly volatile over time. Page 1 of Exhibit ___ (E/D-2) sets forth a regression analysis comparing installed power plant costs (in current $) to the 2003 cost per kWh of operating the plants. Page 2 of the same exhibit explains how the percentage allocations were developed for coal and nuclear units. While these numbers indicate that a 60/40%

demand/energy split for a utility system will likely understate the appropriate allocation of generation capacity costs as "capitalized energy," at least it should make it evident that at least 40% of WPSC's system-wide generation capacity costs should be allocated based on energy. Normally, the Staff TOD method reflects this appropriate assignment of generation costs based on the use of the "equivalent peaker" method to reflect direct causation and "capitalized energy" (which is allocated on the basis of on- and off-peak energy factors).

Q. Does the Applicant's recent sale of the Kewaunee nuclear unit indicate a demand only allocation of nuclear generation capacity costs for WPSC would be appropriate?

A. The practical answer is no. The reason is that the Kewaunee PPA should be allocated for cost of service study purposes in the same manner as if the plant was owned by WPSC. The Kewaunee PPA is a contract for both baseload capacity and energy that was entered into to address WPSC's capacity and energy needs as a result of the sale.

Therefore, it is inappropriate for the WPSC cost study to allocate all of the capacity/demand cost of the PPA solely on the basis of system peak demand. Rather, the capacity costs in the PPA should be divided into production demand costs and "capitalized energy" costs and allocated on the basis of demand and energy, respectively. Page 2 of Exhibit ___ (E/D-2) indicates that a far greater percentage of nuclear generation capacity costs (25% demand/75% energy) should be treated as "capitalized energy" than the system-wide 60% demand/40% energy split recognizes. We have used a conservative 40% demand/60% energy split.

Indeed, this approach should be applied to any PPA or purchase power arrangement in which capacity/demand charges have been incurred to acquire lower cost energy. The failure to treat such PPAs in this manner will not allocate such costs on direct cost causation and result in an inequitable and inappropriate allocation of such costs among the various customer classes.

Q. Do you have any other concerns about the demand allocator used by the Applicant to allocate generation capacity cost in its electric cost of service studies?

A. Yes. In addition to allocating all generation capacity costs solely on a peak demand allocator, the demand allocator used by the Applicant is unlikely to accurately reflect cost causation among the various customer classes.

The reason is that a system coincident peak (CP) method based on only a single annual system peak, a single day monthly peak, or a single hour of a peak day for each month may be inadequate and an inequitable basis to allocate production demand costs. The problem is that the use of only one peak hour or one peak day to allocate system coincident peak demand will not accurately reflect cost causation when there are other hours in that peak day or days that are essentially identical in terms of imposing stress on the reliability of the generation system. For example, an extended, flat daily load shape on a peak day (a number of hours that are effectively equivalent during the peak period) should not be excluded from the ‘demand” allocator for production demand costs. Such an exclusion would be inappropriate in terms of cost causation and inequitable unless by sheer coincidence each class’ contribution to peak for each relevant hour during the peak period remains constant over the peak period. WPSC appears to have such long “flat” peak hours.

We recommend that the Commission direct that Staff, utilities including WPSC and interested parties, develop the information necessary to determine whether there is a more appropriate allocator that better reflects cost causation and equity among customer classes to allocate generation capacity costs that are incurred to achieve generation system reliability than the use of a single hour to develop the “peak” day or monthly “peak” allocators. We recommend that the Commission require WPSC, working together with interested parties and Staff, address this issue prior to the next rate filing for WPSC.

Q. Is it appropriate for the WPSC cost of service study to exclude interruptible customer load from the “demand” allocator used to allocate generation, and transmission and other costs?

A. No, it is not. The primary reasons are that (1) such exclusion has no basis in direct cost causation and indeed is contrary to cost causation in that it fails to allocate direct and indirect costs to interruptible customers that their presence does not avoid, and (2) has the effect of shifting the recovery of such costs that should be borne by interruptible customers to other customers.

Q. Please explain.

A. If a utility is not in an excess capacity situation, interruptible customers provide a valuable benefit in terms of system reliability and costs by potentially avoiding the need for peaking units to reliably meet demand at times of system peak demand or stress (e.g. during periods when baseload units are down for scheduled maintenance). Because of this attribute, interruptible loads do not require the construction of peaking capacity for the times they can be interrupted. This benefit has been reflected in interruptible customer rates through an interruptible credit that in effect removes the per kW cost of peaking units from those capacity costs recoverable in interruptible customer rates.

Under the Applicant's cost of service study approach, excluding interruptible load from the generation "demand" allocator removes interruptible customers from the responsibility of paying for their share of the costs of baseload and intermediate units, which interruptible load clearly contributed to the need to construct and from which they enjoy the lower overall system energy costs that such units provide. In addition, exclusion from the demand allocator also excludes interruptible customers from cost responsibility for many direct plant and generation system operations cost accounts that the presence of interruptible customers help cause rather than avoid. Direct cost causation requires that interruptible customers be responsible for generation costs except to the extent that they avoid the need for peaking capacity (which they receive in the form of the interruptible credit as part of rate design.).

Excluding interruptible loads from the "demand" allocator also means that all those costs (whether direct or indirect) that are allocated on "demand" (or a composite allocator in which demand is a component) will assign no (or under-assign) such costs to interruptible customers. There is no cost causation basis for such an exclusion or under-assignment of these costs to interruptible customers which interruptible load does nothing to avoid. Instead, the result of WPSC's exclusion of interruptible load from the "demand" allocator is to arbitrarily exclude appropriate cost responsibility from interruptible customers and shift it to other customers in the form of greater revenue allocations than appropriate.

Q. How have you reflected the avoidance of peak generation plant costs due to interruptible customers in your analysis?

A. Because of practical limitations, we credited the current interruptible discount to the CP-1 as though the credit represented the costs avoided by interruptible customers. This approach likely understates the CP-1 costs because the current credit to some extent reflects marginal capacity rather than the net plant in the embedded cost studies. An attempt to only remove the interruptible load from plant accounts not caused by interruptible load yielded results more than 50% less than the current credit, which would imply CP-1 costs are understated. Further work on actual costs avoided by interruptible customers is recommended. We recommend that the Commission require WPSC, working together with interested parties and Staff, address this issue prior to the next rate filing for WPSC.

Q. Please summarize your comments on the appropriate allocation of costs that can be directly allocated on the basis of cost causation?

A. The most appropriate treatment of costs that can be directly allocated based on cost causation is normally set forth in the Staff TOD study. This treatment best reflects the factual basis of why costs are incurred and a customer class's responsibility for contributing to the incurrence of such costs. The TOD study appropriately recognizes that generation capacity costs should be split into production demand and "capitalized energy" costs. It also appropriately reflects cost causation by allocating fuel/energy costs on the basis of on- and off-peak energy factors. In addition, the TOD study includes interruptible customer loads to ensure that such customers pay for those costs which their presence does not avoid. For these reasons, we have used the methods we expect in the Staff TOD study as the base line for our analysis in the second step of the appropriate treatment of costs that cannot be allocated based on direct cost causation or based on any meaningful indirect relationship to cost causation.

The second step in the "2 step" process is necessary and appropriate because costs that cannot be directly allocated on a factual basis based on cost causation must be allocated based on assumptions about indirect relationships that are substantially driven by subjective judgments. As a result, the question that should be asked in making these subjective allocations is what basis is there to allocate a particular set of costs that cannot be allocated based on direct cost causation among the various customer classes on something other than an equal per kWh basis?

The most important costs in this category to consider for further analysis are: (1) the costs of the "minimum distribution system" calculated by WPSC in its cost of service study and (2) the allocation of A&G costs.

Q. Are the WPSC cost studies' use of a "minimum distribution system" to allocate some portion of utility-side distribution costs on a per customer basis based on direct cost causation or even a meaningful indirect relationship?

A. No. There is no direct or meaningful indirect cost causation relationship that justifies the allocation of significant costs of the WPSC distribution system on a per customer basis as the "minimum distribution method" used by WPSC seeks to do. While we agree that there are certain customer-side distribution costs (meters and a truly minimum size service drop) that can be directly assigned to various customer classes on a customer-weighted basis, the costs of a utility-side "minimum distribution system" (beyond the service drop) are incurred to provide a common system to provide energy to all customer classes.

Q. Please explain further.

A. WPSC presents two interrelated justifications for allocating the costs of a "minimum distribution system" on a per customer basis: (1) the "minimum distribution system" represents the minimum size system possible to allow customers to have access to power (albeit the "system" at least theoretically could not actually provide energy service to any customer) and (2) the costs of a "minimum" system vary "to some degree" with the total number of customers. (Additional Direct Testimony of WPSC witness Kyto at p. 2)

Neither of these alleged justifications for allocating substantial costs of the WPSC distribution system on a per customer cost has any basis in direct or meaningful indirect cost causation nor provide an adequate justification for a per customer allocation that imposes most of the costs of a "minimum distribution system" approach on small customers.

Q. Is the concept of a "minimum distribution system" based on the ability to have access but not use power appropriately?

A. A hypothetical "minimum distribution system" to provide access has no counterpart in the real utility world. It is similar to charging customers an entry fee to cover the cost of building a grocery store in order to have the opportunity to shop there. Utility distribution systems have been and are built because customers want to purchase energy services, not just to have access. For example, the current WPSC service extension rules are predicated on the requirement that revenues from new customers from the sale of energy services will exceed the cost to extend the distribution system or else the utility will not extend the system except at the cost of the applicant customer.

The costs and components of a "minimum distribution system" (such as the cost of clearing land, digging trenches, putting up poles, installing transformers, etc.) are an "inescapable, indivisible burden of installing any capacity at all." (Alfred Kahn, <u>The Economics of Regulation</u>, Vol. I at p. 126, The MIT Press, 1988) These "indivisible" outlays are in effect the economies of scale that allow greater demand to be met at lower costs than if distinct distribution systems had to be built for different size customers based on their demand (both within and between customer classes). Allocating these minimum costs on a per customer basis has the effect of providing the bulk of the benefits of a common distribution system to those customers who receive minimal cost allocation based on the number of customers. There is no basis in direct cost causation to assign economies in such a manner for a common system that was built to provide energy service to all customers. This alleged basis for the "minimum distribution system" is pure fiction and has no relationship to direct cost causation or why utilities have built their distribution system.

Q. Does the "minimum distribution system" method calculate costs that primarily vary on the basis of total number of utility customers?

A. No. Indeed, WPSC does not even claim that "minimum system" costs primarily vary according to the total number of utility customers, merely that there is some 'relationship" of undefined strength. (Kyto Add. Direct at 2) A consideration of the key drivers of "minimum system" costs reveals that the primary cost drivers have no direct or meaningful indirect causal relationship with the total number of customers.

The primary cost drivers of a minimum distribution system are: (1) the area or size of the service territory that the system must cover; (2) the geologic and meteorological conditions which affect the cost to build a minimum system; (3) external factors such as local governmental requirements (e.g., undergrounding) that affect costs; (4) the type of distribution system (e.g., in a distribution network system the substations serve all customers) and (4) customer density (increased density decreases average cost as opposed to assuming the total number of customers increases costs).

These primary cost drivers of a "minimum distribution system" however are ignored by analysts who perform a "minimum distribution system" approach because they do not fit into one of the three cost allocation categories that some analysts restrict themselves to (demand, energy, and customer). Rather, these analysts (as WPSC has apparently chosen to do) decide to allocate all of the costs of a minimum distribution system on the basis of what is at best "a very weak" indirect correlation between such costs and the total number of customers. As Professor Bonbright has explained about "minimum distribution system" costs:

> Their inclusion among the customer cost category is defended on the ground that, since they vary directly with the area of a distribution system they therefore vary *indirectly* with the number of customers.
>
> What this last-named cost imputation overlooks of course is the *very weak correlation* between area (or the mileage) of a distribution system and the number of customers served by this system. Indeed, if the company's service area stays fixed an increase in the number of customers does not necessarily betoken any increase whatever in the costs of a minimum size system.

James C. Bonbright, Principles of Utility Rates, 1961 Edition, at 348.

Bonbright also emphasizes that "minimum distribution costs" for such reasons are "a strictly unallocable" cost that are inappropriately dumped into the customer cost category because they cannot be directly allocated to the demand or energy cost categories either (based on the underlying justification to use a "minimum system" approach). *Id.* at 347-349.

Q. Why is the appropriate allocation of "minimum distribution system" costs so important?

A. It is important not only because of the magnitude of such costs themselves, but even more because it affects other allocators that are used to indirectly allocate a substantial amount of other costs. Therefore, the inappropriate allocation of such costs will allocate what are effectively other unallocable costs in a highly unequal manner (on a per kWh basis) without any compelling justification for such a result.

Q. How should "minimum distribution system" costs be treated for cost of service study purposes?

A. One option is simply not to use such a method given that the hypothetical and inappropriate basis for calculating such costs has no basis in direct cost causation or any meaningful basis even with an indirect correlation. This would mean that these costs could be allocated on the same basis as the "demand" costs of the distribution system (which is what most regulatory commissions do).

A second alternative is to treat such costs as the "unallocable" costs that they are rather than continue the fiction that such costs have any direct or primary indirect cost causation with the total number of customers. They should be allocated as if they were "unallocable" costs as Bonbright posits.

Q. How would you allocate these "minimum distribution system" costs if they were appropriately treated as an "unallocable" cost?

A. The Applicant's cost of service study allocates "minimum distribution system" costs to the residential class that constitute over 180% (535% for rural customers) of the average per kWh for these costs if they were allocated on an equal per kWh basis to the various customer classes. (We have proposed no allocation of such costs to the large industrial classes due to their very limited direct use of the secondary distribution system.) As we have explained, there is no compelling justification for such a widely disparate allocation and resultant impacts. Therefore, we propose that given the weakness or limited and indirect basis of the justifications for allocating "minimum distribution system" costs on a per customer basis, that the Applicant's proposed deviation from an equal per kWh allocation be moderated for an allocation of the "utility-side" "minimum distribution system."

We propose that the RG-1 customer class be assigned no more than 150% of the equal per kWh average, the RG-2 class no more than 300% of the average (a much higher allocation to recognize the greater lengths of certain system components and lesser customer density). Small farm and commercial customers would also have these same average per kWh for the minimum system. Large farm and commercial (except the largest commercial customers in the CG-20 class) would be increased to near the average per kWh to offset the minimum system costs that cannot be recovered using these allocations. Such an allocation of costs would be far more equitable given the absence of any basis in direct cost causation or a meaningful indirect correlation.

Q. Are there other problems with using a "minimum distribution system" approach?

A. Yes. While in theory a "minimum system" cannot provide service to customers, the reality is that a "minimum size" system constructed from real equipment can in fact supply some level of customer's demand. Due to its nature, a greater percentage of the demand of smaller customers (e.g., residential) will be met than for larger customers (e.g., large commercial customers). Therefore, unless customers are credited in the demand allocator to allocate distribution costs with the demand inherent in the "minimum system" customers, especially smaller customer will pay for distribution costs twice. There is no justification for such a result. We have not found any such crediting in WPSC's application of the "minimum distribution system" method. Based on WPSC's response to an information request, most or all of the demand of the "average" residential customer could be met by the "minimum distribution system" calculated by WPSC.

Thus, we have adjusted the urban residential demand contribution to zero and reduced the rural residential demand contribution by 50% to adjust for the double counting.

Q. Does your discussion of the "minimum distribution system" in the electric costs of service extend to the Applicant's use of a "zero intercept" method to allocate gas main costs in its natural gas cost of service study?

A. Yes, except that the use of a " zero intercept" approach basically eliminates the concern about double-counting costs when a "minimum system" approach is used. Otherwise, the allocation of natural gas mains on a per customer basis has even less of a basis in direct or indirect cost causation.

Natural gas is a discretionary service that customers utilize because it is less expensive than other commonly available alternatives. Customers seek natural gas service to use it not just to have access to such service. The natural gas main system was built to satisfy this demand, not on the theory that if you build it people will hook up, then decide if they really might want to use natural gas. Indeed, the natural gas main system has been constructed not only to satisfy peak demands but also to allow significant through-put to satisfy the non-peak demands of customers. For these reasons, the use of a "zero-intercept" method for gas mains is the natural gas fictional version that seeks to justify the allocation of a meaningful portion of gas main costs on a per customer basis. The costs of natural gas mains should be fully allocated on the basis of demand and commodity to properly reflect why the costs of gas mains have been incurred.

Q. What change to the Applicant's allocation of Administrative & General (A&G) costs do you propose?

A. A&G costs represent firm overhead costs that are not directly related to a specific class of customers. Therefore, the per kWh allocation of A&G costs for small customers should be moderated in a similar method to the treatment of the minimum distribution system. The per kWh allocation to all customers in our COSS is moderated to 150% of the average per kWh cost except for CG-20 and CP-1 customers. The CG-20 customers are moderated to near the average per kWh cost with no adjustment to CP-1 customers.

Q. What is shown in Exhibit ___ (E/D-3)?

A. Exhibit ___ (E/D-3) provides several schedules that describe the Step 2 process in considering and moderating the allocation of “minimum distribution system” and A&G costs proposed by the Applicant. All of the schedules use the same Staff TOD methodology to allocate costs that can be allocated on direct cost causation and, as noted previously, do not change the Applicant’s treatment of linked or other costs. The only variations shown in these schedules are the result of different proposed treatments of the allocation of minimum system and A&G costs.

Schedule 1 of the exhibit compares the Applicant’s and CUB’s cost study results on an average per kWh basis for each customer class. The shaded area of the chart shows the proposed per kWh rate increases by rate class for the Applicant’s cost allocation methods including for “minimum system” distribution and A&G costs (labeled “Extreme”). The bars on this chart reflect per kWh increases based on a reasonable moderation of the Applicant’s proposed allocation of “minimum system” and A&G costs and correcting for the double counting of “minimum system” costs that underlies CUB’s COSS. We emphasize that the rate increase labeled as “moderated” is not the bottom of an appropriate range. Indeed, given the lack of direct or strong indirect cost allocation for an unequal per kWh of these costs, our approach is only more moderate compared to the extreme position proposed by the Applicant.

Schedule 2 contains a chart showing the allocated cost per kWh as a percentage of the average cost per kWh for "minimum system" and A&G costs based on the Applicant's COSS. The chart identifies the unreasonable and unjustified per kWh impacts proposed by the Applicant that we moderated. Schedule 3 shows the same percentage as Schedule 2 for the "moderated" rates proposed by CUB for these costs. Schedule 4 presents the various cost accounts and how they were treated by cost causation category in the CUB COSS.

III. RATE DESIGN

Q. Do you have any general comments about the residential rate design issues in this proceeding?

A. We agree with many of the Applicant's statements about the importance of developing effective rate design options and the observation on the limitations of the current residential rate designs. (*See* e.g., Direct Testimony of WPSC witness Ferguson at 21.) While we have had the opportunity to discuss some of these general issues with the Applicant, there remain two primary issues for CUB: (1) the pace at which new residential rate design options will be developed and implemented and (2) the specific designs that receive consideration for development.

Q. Please explain your concern about timing.

A. We have both been involved in the process of developing and implementing new programs and/or rate designs. Therefore, we understand the resources and time commitments that the effective development of new efforts entails. In addition, developing the information needed, especially as to customer acceptability and value, takes time and planning. The above statements also recognize that there is typically more than one such program development or effort underway (e.g., the direct load control/thermostat pilot).

However, there are compelling reasons why the development of more effective residential rate designs (and designs better integrated and coordinated with other energy efficiency and load management efforts) should occur sooner rather than later. <u>First</u>, WPSC is facing additional increased costs, in part due to the need to improve its existing infrastructure (e.g., new generation units around the 2011 time frame and thereafter). The sooner there are effective efforts to mitigate the growth in customer demand, the sooner that WPSC rates may return to a more stable and reasonable level by mitigating the need for such an ambitious construction program. <u>Second</u>, new residential options need to keep pace with the availability of appropriate improved designs and options for other customer classes. It would be inappropriate to allow one class of customers more effective options than another, especially if there is a meaningful length of time in which such a disparity of options might continue. Especially during periods of increasing rates, it should be an objective to increase effective opportunities to control bills for all customer classes within a common time frame to avoid cost shifting due to only one class having such meaningfully improved options available.

Q. Do you have a recommendation on how to proceed with developing improved small customer rate designs for WPSC?

A. Yes. As the Applicant proceeds with its DLC/thermostat pilot, we believe that WPSC should accelerate its development of residential time-of-use (TOU) options so that an improved design is available to pilot in 2006. We would recommend that WPSC work with interested parties such as CUB in order to get input that would be intended to help accelerate a final and most effective alternative. In our testimony that follows, we describe the array of potential designs that we believe should be considered.

Q. What are your conclusions about the utility's proposed residential rate design?

A. The proposed rate designs in this case do not provide residential customers enough opportunities to reduce costs to the utility while reducing their own bills. Our conclusions on the utility rate design are discussed below concerning flat residential rates and time-of-use residential rates. Flat residential rates are rates that do not vary with the time of electricity use nor the quantity of electricity use. Time-of-use rates do vary with the time when the electricity is used.

<u>FLAT RATES</u>

<u>Flat rates have the following problems:</u>

1. Customers' attempts to save money can increase costs instead of save costs.
2. Customers reducing above average costs to the utility are not treated fairly.
3. Flat rates are not equitable to customers on the rate because of differences between customers that impose different costs on the utility.
4. Customers have no way of understanding the value of peak reduction and no compelling motivation to reduce energy use during high cost time periods.

TOU RATES

The current WPSC residential TOU rates raise the following concerns:

1. The current TOU rates are most beneficial to customers with electric space heating or water heating rather than encouraging reduced contribution on peak.
2. The high on-peak rate is too high and combined with long on-peak time period discourages most residential customers from moving to this rate.

FLAT RATES

Q. How could the current flat rates result in cost increases when customers attempt to save money?

A. Customers concerned about the cost of electricity can leave their air conditioner turned off until the hottest time. The air conditioner then would operate several hours continuously at full power until it reaches the thermostat set point. An air conditioner rated for 2.5 ton cooling capacity would have a peak contribution of 3 kW exceeding the 1.7 kW the air conditioner would have used if cycling on and off under continuous thermostat control. This happens because air conditioners' cooling capacity exceeds the peak cooling load. The incremental power plant cost of capacity for the extra 1.3 kW of load would cost $85 compared to the total annual electric charge for air conditioning of $64.

Q. Explain how customers whose actions can reduce utility costs are not treated appropriately to encourage such actions.

A. Flat residential rates subsidize air conditioning use. The current electric rates yields utility revenue of approximately 40% (WPSC proposed rates yields 44%) of the incremental production costs to supply air conditioning even without the cost of transmission and distribution facilities. The electric rates of all residential customers have to make up the difference.

A customer who spends thousands of dollars on a new efficient air conditioner might reduce the utility cost loss above the current price in half (over $75 per customer per year). The flat rates would only yield approximately $30 of benefit to that customer, thereby providing a more limited incentive to undertake such an action.

Q. Why are flat rates not equitable to customers on the rate because of usage difference between residential customers?

A. Differences in the way customers use their air conditioners cause substantial difference in costs to the utility. At one end of the range are customers who cause extra high-peak capacity needs while providing minimum payments for costs because they operate their air conditioners relatively few hours (which happen to be at the time of system peak). Other customers cause minimal peak capacity by not operating their air conditioners at all during peak capacity needs. These customers might work during critical cost time periods and not use their air conditioner until after the system peak.

Q. Do flat rates provide useful price signals to customers?

A. No. Customers have no way of knowing the value of peak reduction or reducing energy use during high-cost time periods.

TOU RATES

Q. What percent of WPSC residential customers are on residential time-of-use rates?

A. The residential time-of-use rates are voluntary with only about 3.6% of residential customers choosing the TOU rates.

Q. Which customers benefit most from the current residential TOU rates?

A. Customers with electric space heating or other significant off-peak energy use. The proportion of electric space heating customers is twice as high as the proportion on the regular flat rate.

Q. What about the TOU rates discourages residential customer choice of TOU rates?

A. The very high on-peak rate and the long on-peak time period.

Q. Is the on-peak rate too high?

A. Yes. The utility proposed on-peak rate is 13 cents per kWh above the marginal energy cost of six cents per kWh. This margin above energy costs charges an average of $440 per customer per year. If the reason for the higher on-peak rate were peak production costs, the $440 would be enough to pay for 6.7 kW of residential peak. The 6.7 kW would be nearly four times the contribution of a central air conditioner which is a primary cause of residential peak load contribution.

Q. What potential flawed rate design strategies might lead to too high of on-peak charges?

A. 1. A strategy of setting the off-peak rate near the marginal energy costs and recovering the rest of the revenue requirement from the on-peak rate. This strategy was historically used to reduce the impact of eliminating special discount rates given to electric space heating customers. The electric space heating rates were eliminated under a policy that it was no longer reasonable to promote electric use.

2. A strategy that assumes the on-peak rate must be high enough that customers are forced to defer consumption from the on-peak times to off-peak times. This strategy was initially based on an obsolete assumption of needing to recover metering costs by producing the same amount of energy at a different low cost time. But the utility now has automatic meter reading so different metering is not required. The strategy is also flawed because reducing peak capacity needs based on the value of peak reduction is a worthy goal without deferring energy consumption to a low cost time period. Finally, TOU rates were initially implemented under an expectation that TOU rates would be mandatory for a substantial number of customers. With voluntary TOU rates, it is appropriate that the TOU rate be designed so that it is chosen by customers as a way of reducing utility costs (while at the same time helping to mitigate future costs for WPSC). It is simply

reasonable to allow customers who cause costs to pay for costs and those that do not cause costs to have a reasonable choice to avoid costs.

3. A strategy of balancing the on-peak and off-peak rate to produce (for the average residential customer) the same, if not more revenue, under the time-of-use rate as the flat rate. This strategy is contrary to cost based pricing and providing price signals.

Q. Why do you believe the current on-peak time period is too long?

A. The time period is too long because: a) a shorter time period will produce more benefits, and b) the number of peak hours related to reliability are substantially less than the current on-peak time period.

Q. Why will a shorter on-peak time period produce more benefits?

A. Currently, residential time-of-use rates in Wisconsin are typically voluntary options. When the on-peak time period is so long that few customers view the rate as an opportunity to manage their electric bill and satisfy their needs, there are few benefits gained because of lack of participation. Even if the utility has a longer time period due to high fuel costs, it still is valuable to reduce capacity (reliability) related costs in a way that customers can understand and choose. Because air conditioners operate the least efficiently when the difference between the indoor and outdoor temperatures are extreme, reducing air conditioning use during the hottest part of the day can reduce both peak capacity and save energy even if the same amount of cooling takes place over the current on-peak time period.

Q. Explain the number of hours that could be more reasonable than the current on-peak time-period offered by WPSC.

A. Utilities we have met with on behalf of CUB have given us the impression that there are 300 or fewer hours that are critical from a cost and reliability (generation capacity) perspective. These hours are primarily weather related and compare to approximately 400 full-load equivalent cooling hours. Also, 300 hours is also the time period contained in some interruptible rates.

The current on-peak time period includes 1,288 summer hours and 2,577 winter on-peak hours and are just too many hours to be of value to many residential customers. It is much more practical to communicate to customers the value and practical ways of reducing dehumidifier and air conditioning use from 12:00 to 5:30 p.m. in the summer rather than be overwhelmed by trying to figure out what electrical use might be important over thousands of hours.

Q. What suggestions do you have if WPSC is concerned about reducing customer demand or usage beyond the 12:00 to 5:30 p.m. time period?

A. The utility should consider using integrated load management from all customers rather than expecting a single customer class to reduce use during all hours. For instances, the air conditioners in offices could be turned off slightly before many customers leave work and go home. Then cooling the office building structure down before occupancy could reduce the load during morning hours.

Q. Do you believe a single time of use rate is sufficient?

A. No. The current residential rate is sufficient for a few residential customers, especially those with electric space heating. But, there are more than one segment of customers whose preferred electrical consumption creates substantially different utility costs.

Q. What time-of-use rate would you suggest?

A. We suggest a time-of-use rate with the following components:

1. Off-peak rate 15% below regular flat rate (e.g., 8 cents per kWh)
2. On-peak rate menu consisting of:
    a. Economy rate - (e.g., 11 cents per kWh)
    b. Moderate CAC - (e.g., 14 cents per kWh)
    c. Regular - (e.g., 19 cents per kWh)

Off-peak

The off-peak rate would apply most of the year and be at a specific level approximately 15% below the standard flat rate.

On-Peak

The on-peak rate would apply for summer months from 12:00 to 5:30 p.m. A customer would be able to choose from a menu of options that best fits their needs and interests and which help mitigate future utility costs.

- **Economy on-peak rate**

The economy on-peak rate will provide a lower level of reliable central air conditioning on-peak than customers on the moderate rate and is for customers who want air conditioning but do not depend on a high degree of air conditioning between 12:00 and 5:30 p.m. The customer may buy a communicating thermostat that provides a reasonable degree of comfort and allows the utility to routinely reduce the level of air conditioning at times beyond a peak day. Customers paying for lower cost controls than communicating thermostats would risk the lowest level of central air conditioning as the utility will routinely limit air conditioning to save peak energy costs. During extreme weather in conjunction with capacity shortage, these customers will be the first to be turned off and left off as long as needed for reliability reasons.

- **Moderate on-peak rate**

The moderate use on-peak rate will provide a comfort choice to customers while reducing peak energy use 50% below the peak level of typical customers on the regular on-peak rate. Customers with high efficiency central air conditioners (i.e., SEER 14) are a primary target for this rate. Customers who allow control of the high stage of a two-stage central air conditioner could also be eligible. Customers with inefficient central air conditioners could use the rate too if they allow their air conditioners to be controlled to use no more than efficient air conditioners from 12:00 to 5:30 p.m. Customers with inefficient central air conditioners would also be required to have controls eliminating dehumidifier use from 12:00 to 5:30 p.m. During extreme weather in conjunction with capacity shortage, the central air conditioners of these customers will be turned off only after interruptible customers and economy rate residential customers and will be controlled as needed for reliability reasons.

- **Regular on-peak rate**

The customers on the regular on-peak rate would in normal years choose how much central air conditioning they want to use and pay the rate applicable at the time of consumption. While generally unlikely to happen and unlikely to last long enough to impact comfort, the central air conditioners of these customers may be turned off as a last resort to avoid the cost of generation reserves for very rare situations. Control of these central air conditioners would only occur after all other controllable load is interrupted.

Q. Are the benefits of the residential TOU rates received entirely by participating customers?

A. No. While the benefits of less generation capacity needed to serve TOU customers than typical regular customers will be over $100 without considering the energy related benefits, the benefits for a typical sized customer will be less than $100. The benefits of TOU customers will however exceed the benefits given to current participants of direct load control.

Q. Should the current direct load control credits continue for residential TOU customers?

A. No.

Q. What should be done with any benefits that are not provided to TOU customers?

A. We suggest using the monetized value of the additional benefits to increase customer satisfaction of TOU customers while helping to mitigate future utility costs. For example, a reward of $200 could be given towards the purchase of an efficient central air conditioner if the customer committed to three years on the regular on-peak rate. The monetized value could also be used to contribute towards the cost of controls like a communicating thermostat that might reduce comfort issues.

Q. Should the benefits produced from TOU rates be used to keep the rate lower for customers on the flat rate?

A. No, artificially holding down the flat rate is counterproductive. Customers causing the most costs above the flat rate price would then enjoy receiving service at even more of a below cost basis. At some point, a consideration of making voluntary TOU rates mandatory may be appropriate.

Q. Do you agree with the utility's tentative electric rate design timeline provided to CUB?

A. No. While the timeline lists a decision on residential offerings in 2005, there is no corresponding implementation from the decisions in 2006. Residential customers are not specifically mentioned in 2006. The first implementation of residential rate design efforts shows up in 2007 as a pilot pricing option. As a minimum, some research, preparation, and introduction of improved residential pricing should begin in 2006.

Waiting to develop a pilot in 2007 is too long if that is what the information shared with us indicates.

Q. What other concerns do you have relative to the proposed 2007 residential TOU pilot?

A. WPSC appears interested in three-tier time-of-use rates and other potentially complicated and expensive pricing options. Since the TOU rates discussed above are our preference at this time, something needs to be done to resolve what customers will actually have available in 2006 and 2007. Work completed in 2006 should include resolution and/or information gathered that is needed to resolve residential TOU issues and prepare to offer a menu of choices that customers find of value in 2007. Specifically, efforts in 2006 are needed to develop and prepare for many, if not all, residential customer choices for improved rate designs that may provide improved value to customers and WPSC.

Q. Have you talked with WPSC about the practical aspects of changing the proposed schedule for developing and testing improved residential rate designs?

A. Yes. From conversations with the utility, there does not appear to be any significant or unresolvable major technical obstacles. The cost of residential TOU metering does not appear to be an issue considering the use of AMR technology by WPSC. While WPSC is hesitant now to commit to the costs probably necessary to greatly expand the residential TOU rate, the only estimate of cost provided to us is less than one dollar per customer ($200,000 to $300,000 for additional staff and computer hardware). Changes to the utility billing system due to be completed September 2005 and lack of knowledge on the resources or potential limitations on how many TOU customers can be practically handled, also contribute to the difficulty of making more accurate cost estimates at this time. But, WPSC does seem to be willing to allow as many residential TOU customers as they can handle to participate

Q. What should the Commission require?

A. Before making our recommendations, we wish to acknowledge WPSC's recognition of the need and desirability for improved residential (and for other customer class) rate designs that provide better price signals but also an improved opportunity for customers to be able to effectively respond to such signals to better manage their utility bills. However for reasons previously explained, CUB is concerned about the pace of developing new residential rate design options and the nature of the menu of options that will be pursued.

Within the above context, we recommend that the Commission require WPSC to file a report by March 1, 2006 explaining what WPSC will do in 2006 to improve residential pricing issues and to provide a valuable menu of pricing options for many, if not all, residential customers in 2007. The Commission should require that WPSC develop the TOU proposal made by CUB as part of its plan for new designs. WPSC, as part of its March 2006 filing, should also file "pilot" tariffs or other proposals to test new designs for Commission approval in order for them to be implemented during the summer of 2006 so that broader applications of such tariffs/designs can be implemented in 2007. Approval for the broader application of these tariffs/proposals for 2007 should be submitted to the Commission no later than November 1, 2006. The Commission should allow interested parties to comment on the March, 2006 report, as well as the "pilot" or expanded tariff/proposal filings. The Commission should retain jurisdiction pending the need to resolve disagreements or to ensure better results in a timely manner.

Q. Has the DLC collaborative (which originated out of WPSC's last rate order) with you as CUB consultants on direct load control been useful?

A. Yes. We commend WPSC on the work done thus far in developing and considering improved load management options for residential (and other small) customers. It is our opinion that meetings of the group have been constructive and valuable for all involved, including developing a work plan for continuing efforts. However, a crucial point will be reached when the initial information is gained from the current pilot and used to inform what rate design options will further be explored.

Q. Has WPSC funded your work in this DLC collaborative?

A. No.

Q. Does this complete your direct testimony?

A. Yes.